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DISCUSSION PAPERS IN ECONOMICS, FINANCE AND INTERNATIONAL COMPETITIVENESS

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Discussion Paper No. 114, July 2002

Series edited by
Dr Andrew Worthington

School of Economics and Finance

ISSN 1324-5910

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Transmission of prices and price volatility in Australian electricity spot markets: A multivariate GARCH analysis

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Abstract
This paper examines the transmission of spot electricity prices and price volatility among the five Australian electricity markets in the National Electricity Market (NEM): namely, New South Wales (NSW), Queensland (QLD), South Australia (SA), the Snowy Mountains Hydroelectric Scheme (SNO) and Victoria (VIC). A multivariate generalised autoregressive conditional heteroskedasticity (MGARCH) model is used to identify the source and magnitude of spillovers. The results indicate the presence of positive own mean spillovers in only a small number of markets and no mean spillovers between any of the markets. This appears to be directly related to the limitations of the present system of regional interconnectors. Nevertheless, the large number of significant own-volatility and cross-volatility spillovers in all five markets indicates the presence of strong ARCH and GARCH effects. Contrary to evidence from studies in North American electricity markets, the results also indicate that Australian electricity spot prices are stationary.

JEL classification: C51, G15
Keywords: spot electricity price markets; mean and volatility spillovers; multivariate GARCH

1. Introduction

Electricity plays a vital role in all developed economies, including Australia. However, the Australian economy's reliance on electricity generation, transmission and distribution has for the most part (and in common with most other economies) been largely taken for granted. The overall result has been that until comparatively recently the electricity supply industry has assumed a lesser role in the economic agenda when compared to many other industries. This is paradoxical, especially when one considers the importance of electricity in Australian economic development (Dickson *et. al.* 2000: 5):

The Australian electricity industry is one of the most important sectors of the Australian economy. With over $74 billion in assets, 33000 employees and annual investment of over $2.4 billion, it directly contributes an estimated 1.4 per cent to gross domestic product.

However, in the last decade of the twentieth century the electricity industry in Australia and around the world changed significantly as governments, suppliers and consumers recognized its importance within the broader themes of globalization and competitive reform. This lead to an important paradigm shift, entailing a move away from the heavily regulated, vertically integrated state-based monopolies of the past to more market-based structures for electricity suppliers in the present, and towards potentially more competitive outcomes for consumers in the future. The many reforms reached their culmination with the establishment of the National Electricity

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Market (NEM) on 13 December 1998 when the five regional spot electricity markets were joined together (NEMMCO: 2000: 2). All the same, it should be noted that very gradual move to an integrated national system was predated by substantial reforms on a state-by-state basis, including the unbundling of generation, transmission and distribution and the commercialization and privatization of the new electricity companies, along with the establishment of the wholesale electricity spot markets. For example, the wholesale market for electricity in Victoria and New South Wales commenced as early as 1994 and 1996, respectively, though it was not until 1998 that the market for electricity in Queensland began.

Unfortunately, despite the key importance of market pricing within each spot market and the integration of the separate state-based electricity markets within a single national market, very little empirical evidence currently exists in Australia concerning the pricing behaviour of the deregulated electricity market. This is important, not only because "…the spot price strongly influence the contract price which, in turn, largely dictates the final price for consumer [but also] because the spot price represents a considerable element of cost for direct purchasers of power, such as large industrial companies" (Robinson 2000: 527). The short tenure of the Australian electricity spot market is the most apparent, though not the only, reason. In actual fact, very little work has been undertaken in any context that provides a detailed understanding of electricity price behaviour and almost none using the advanced econometric techniques so increasingly widespread in work on, say, financial markets. The few studies that do exist are especially noteworthy.

Deng (2000), for example, proposed several stochastic models of energy commodity price behaviour specifically in the context of a deregulated electricity industry. Using a number of models and assumptions [including mean-reversion, jump-diffusion and regime-switching] Deng (2000) aimed to more accurately reflect the physical characteristics of electricity in commodity spot price behaviour models as a first step in applying a real options approach to valuing physical assets in the electricity industry.

An earlier study by De Vany and Walls (1999a) took a somewhat different approach to understanding electricity pricing behaviour by examining regional power markets in the western United States for evidence of integration over the period December 1994 to April 1996. The eleven regional markets analysed included California/Oregon, Four-Corners, Central Rockies, Inland Southwest, Mead, Mid-Columbia, Midway/Sylmar, Northern California, Northwest/Northern Rockies, Palo Verde and Southern California. Using daily spot prices collected from the day ahead over-the-counter market De Vany and Wall (1999a) employed Augmented Dickey Fuller (ADF) unit root tests to first detect the presence of non-stationarity in both peak and off-peak series for all markets, with the exception of off-peak prices in the Northern California market.

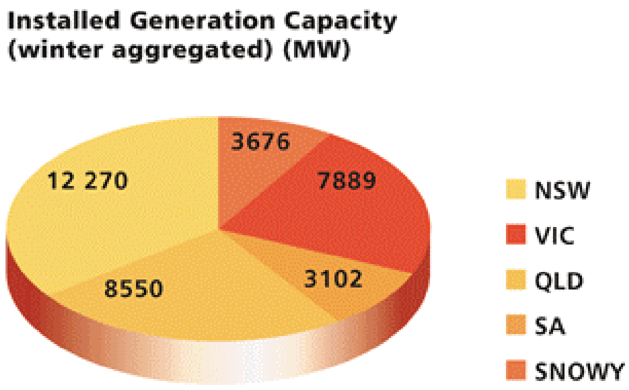
De Vany and Walls (1999a) also applied cointegration analysis to test for price convergence between these markets. The results indicated a high degree of market integration between the not necessarily physically connected markets, with cointegration being found for peak prices in forty-eight of the fifty-five market pairs (87 percent) and all fifty-five market pairs for off-peak prices. De Vany and Wall (1999a) argued that the lack of cointegration in several markets was evidence of transfer constraints within some parts of the Western Electricity Grid, though on the whole the study's findings was suggestive of an efficient and stable wholesale power market. A subsequent study by Lucia and Schwartz (2001) also used cointegration techniques, though in the context of the deregulated Norwegian electricity market and with an emphasis on the relationship between spot and derivative electricity prices. Using a sample of 2,555 daily prices (including peak and off-peak) in the period commencing 1 January 1993 Lucia and Schwartz (2001) concluded that electricity prices in both the Norwegian spot and derivative markets were stationary.

In an alternative approach, De Vany and Walls (1999b) specified a subset of five of the eleven previously used regional markets [CA-OR-NV Border, 4-Corners, Inland Southwest, Palo Verde and Southern California] to apply vector autoregressive (VAR) modelling techniques. As in the earlier cointegration analysis, the study confirmed that both peak and off-peak spot prices for electricity contained a unit root. The results of separate variance decomposition analyses also indicated that during off-peak periods, the larger proportion of price shocks were absorbed locally and only a small proportion of the shocks propagated to other interconnected nodal markets. Conversely, during peak periods a larger proportion of shocks propagated from the originating node to more distant interconnected market nodes. On this basis, De Vany and Wall (1999b: 139) concluded "the wholesale price of power, in peak and off-peak periods, is dynamically stable in the five major markets…prices fall within a narrow range and the average prices at the interconnected points are almost equal to one another". Moreover, "the efficiency of power pricing on the western transmission grid is testimony to the ability of decentralised markets and local arbitrage to produce a global pattern of nearly uniform prices over a complex and decentralised transmission network spanning vast distances" (De Vany and Walls 1999b: 139). It is within the context of this limited empirical work that the present study is undertaken.
The paper itself is divided into five main areas. The second section briefly surveys the establishment and operation of the Australian National Electricity Market (NEM). The third section explains the data employed in the present analysis, while the fourth section discusses the methodology employed. The results are dealt with in the fifth section. The paper ends with some brief concluding remarks.

2. The Australian National Electricity Market (NEM)

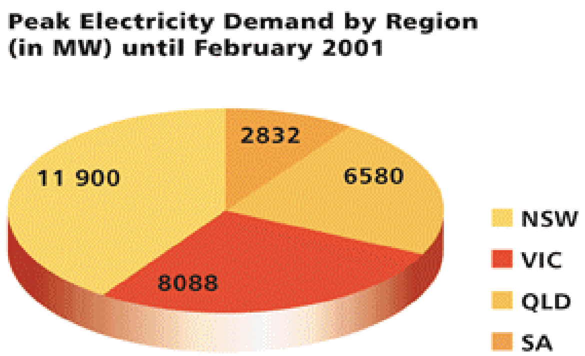
The Australian National Electricity Market (NEM) encompasses electricity generators in the eastern state electricity markets of Australia operating as a nationally interconnected grid. The member jurisdictions of the NEM thus include the three most populous states of New South Wales (NSW) [including the Australian Capital Territory (ACT)], Victoria (VIC) and Queensland (QLD) along with South Australia (SA). The only non-State based member that currently provides output into the NEM is the Snowy Mountains Hydroelectric Scheme (SNO). The SNO is regarded as a special case owing to the complexity of arrangements underlying both its original construction and operating arrangements involving both the state governments of New South Wales and Victoria, as well as the Commonwealth (federal) government. Of these member jurisdictions, the largest generation capacity is found in NSW, followed in descending order by Queensland, Victoria, the Snowy Mountains Hydroelectric Scheme and South Australia.

It is intended that the island state of Tasmania will become a member of the NEM pending completion of the Basslink interconnector, which will link Tasmania's electricity supply industry with that of the mainland. The remaining Australian state of Western Australia along with the Northern Territory are unlikely to participate in the NEM in the foreseeable future due to the economic and physical unfeasibility of interconnection and transmission augmentation across such geographically dispersed and distant areas. At present, the NEM supplies electricity to 7.7 million Australian customers on the interconnected national grid that runs through Queensland, New South Wales, the Australian Capital Territory, Victoria and South Australia. Peak electricity demand is highest in NSW, followed by Victoria, Queensland and South Australia. In terms of net aggregate capacity and demand, NSW, Queensland, South Australia and the Snowy are potentially overall net exporters of electricity while Victoria is a net importer. Some $8 billion of energy is traded through the NEM yearly within these jurisdictions.



The NEM currently comprises more than seventy registered participants within the five member jurisdictions who fall into six categories based on the role they perform in the market. Some participants fill more than a single role within the NEM and therefore belong to more than one category. The categories are: generators; Distribution Network Service Providers (DNSP); market customers (including both electricity retailers and end-use customers); Transmission Network Service Providers (TNSP); Market Network Service Providers (MNSP) and traders.

In terms of electricity generation, the NEM relies on fossil fuels. In NSW, Queensland and Victoria electricity production is almost entirely coal-fuelled, while there are gas-powered stations in South Australia. Hydroelectricity plants operate in the Snowy Mountains region. Generators may be privately or publicly owned and fall into four categories according to their obligation to participate in the NEM. These are: market generators (generators whose entire output is sold through NEMMCO's spot market), non-market generators (generators whose entire output is sold directly to a local retailer or customer outsider the spot market system), scheduled generators (individual or groups of generators with a capacity rating over 30 megawatts, and whose output is scheduled by NEMMCO's dispatch instructions) and non-scheduled generators (individual or



groups of generators with a capacity rating of less than 30 megawatts). All generators or groups of generators with a capacity rating of 5-30 megawatts must register with NEMMCO.

The NEM was developed and operates under a number of legislative agreements, memorandums of understanding and protocols between the participating jurisdictions. They include a mechanism for uniformity of relevant electricity legislation across states, implementation of the National Electricity Code (NEC) and the creation of the National Electricity Code Administrator (NECA) and the National Electricity Market Management Company (NEMMCO) to control and implement the NEM. The NECA is the organisation charged with administering the NEC. This entails monitoring participant compliance with the Code and raising Code breaches with the National Electricity Tribunal (IEA: 2001: 132). Other roles of the NECA include managing changes to the NEC and establishing procedures for dispute resolution, consultative, and reporting procedures (NEMMCO, 2001: 28). The NECA also established the Reliability Panel in 1997, in order to “determine power system security and reliability standards, and monitor market reliability” (IEA: 2001: 132).

The market rules that govern the operation of the NEM are embedded in the NEC, which was developed in consultation with government, industry and consumers during the mid-1990s. NEMMCO (2001: 4) summarises the rationale for the thoroughness of the NEC:

The rules and standards of the Code ensure that all parties seeking to be part of the electricity network should have access on a fair and reasonable basis. The Code also defines technical requirements for the electricity networks, generator plant, and customer connection equipment to ensure that electricity delivered to the customers meets prescribed standards.

The NEC required authorisation by the Australian Competition and Consumer Commission (ACCC) to be implemented, as do any changes. Born from the Hilmer microeconomic reforms in the 1990s the ACCC is the peak Australian body aimed at enforcing competition law. To this affect, the ACCC is responsible for administering the Trade Practices Act (1974), which was augmented under the National Competition Policy (NCP) reforms to facilitate access arrangements to network infrastructure and the addition of competitive neutrality provisions, which ensure there can be no discrimination between public and private service providers. Asher (1998: 10) highlights the key change to the Trade Practices Act (1974) under the National Competition Policy reforms as “establishing a third party access regime to cover the services provided by significant infrastructure facilities” (facilities not economically feasible to duplicate and where the access arrangements would be necessary to promote effective competition in upstream or downstream markets).

In addition to the administration of this role in regard to market infrastructure, the ACCC is the organisation responsible for the regulation of the transmission network component of the Australian Electricity Supply Industry. Of the various facets this role encompasses, transmission pricing is the most prominent. This is managed by the ACCC on a revenue cap basis, in an attempt “to constrain monopoly pricing while allowing the business owners a rate of return sufficient to fund network operation and expansion” (ACCC, 2000: 8). In brief, the ACCC’s price cap methodology is (IEA 2001: 137):

The revenue of transmission companies is regulated on the basis of an adjusted replacement value of the assets, known as deprival value, and its weighted cost of capital. The maximum annual revenue allowed to transmission is subject to a CPI-X price cap, fixed for a period of at least five years, that reduces transmission charges over time in real terms.

The transmission-pricing role is carried out in conjunction with a service reliability protocol, to ensure quality of service. As noted, changes to the NEC effecting transmission or any other aspect of the market must be authorised by the ACCC. As such the ACCC is responsible for the evaluation of changes to market operations. It is the role of the National Electricity Market Management Company (NEMMCO) to implement and administer changes to market operation.

The National Electricity Market Management Company (NEMMCO) operates the wholesale market for electricity trade between generators and retailers (and also large consumers). From an operational perspective, output from generators is pooled then scheduled to meet demand. The IEA (2001: 134) summarises the core elements as follows:

The National Electricity Market is a mandatory auction in which generators of 30 MW [megawatts] or more and wholesale market customers compete. Generators submit bids consisting of simple price-quantity pairs specifying the amount of energy they are prepared to supply at a certain price. Up to ten such pairs can be submitted per day. In principle, these bids are firm and can only be altered under certain conditions. Generator bids are used to construct a merit order of generation. Customer bids are used to construct a demand schedule. Dispatch minimises the cost of meeting the actual electricity demand, taking into account transmission constraints for each of the five regions in which the market is divided…There are no capacity payments or any other capacity mechanisms.

The two key aspects required for the pool to operate are a centrally coordinated dispatch mechanism and operation of the ‘spot market’ process. As the market operator, NEMMCO coordinates dispatch to “balance electricity supply and demand requirements” (NEMMCO, 2001: 3), which is required because of the instantaneous nature of electricity, and the spot price is then “the clearing price [that] matches supply with demand” (NEMMCO, 2001: 3).

The pool rules dictate that generators in the NEM with a capacity greater than 30MW are required to submit bidding schedules (prices for supplying different levels of generation) to NEMMCO on a day before basis. Separate capacity schedules are submitted for each of the 48 half-hour periods of the day. As a result, the industry supply curve (also called a bid stack) may be segmented to a maximum extent of ten times the number of generators bidding into the pool. NEMMCO determines prices every five minutes on a real time basis. This is achieved by matching expected demand in the next five minutes against the bid stack for that half-hour period. The price offered by the last generator to be dispatched (plant are dispatched on a least-cost basis) to meet total demand sets the five-minute price. The price for the half-hour trading period (or pool price) is the time-weighted average of the six five-minute periods comprising the half-hour trading period. This is the price generators receive for the actual electricity they dispatch into the pool, and is the price market customers pay to receive generation in that half hour period.

TABLE 1. *Generator offer prices and total electricity demand per half-hour*

Generator	Generator Offer Prices (half-hour)	Time	Total Demand (MW)
6	$40/MWh	12:05pm	290
5	$38/MWh	12:10pm	330
4	$37/MWh	12:15pm	360
3	$35/MWh	12:20pm	410
2	$33/MWh	12:25pm	440
1	$32/MWh	12:30pm	390

An illustration of spot market pricing in the NEM is drawn from NEMMCO (2000: 12). Table 1 contains offer prices for six generators (in megawatt hours) and demand information (in megawatts) for the six five-minute dispatch periods in the 12:30 trading interval. Assuming each of these generators has 100 MW (megawatts) of capacity, Figure 1 graphically analyses the least cost dispatch for these five-minute intervals. For example, at 12:05 total demand is 290 MW and to meet this demand the full capacity of the lowest priced generators 1 ($32 MWh) and 2 ($33 MWh) and most of the capacity of generator 3 ($35 MWh) is required. The marginal price for this five-minute interval is then $35 MWh. This information, along with the remaining five-minute intervals until 12:30, is tabulated in Table 2, which shows the marginal price for each five-minute interval as a result of the plant dispatch mix, which is primarily dependant on the level of demand. The pool price for the 12:30 trading interval is the average of these six five-minute marginal prices.

FIGURE 1. *Least cost dispatch and generator utilisation*

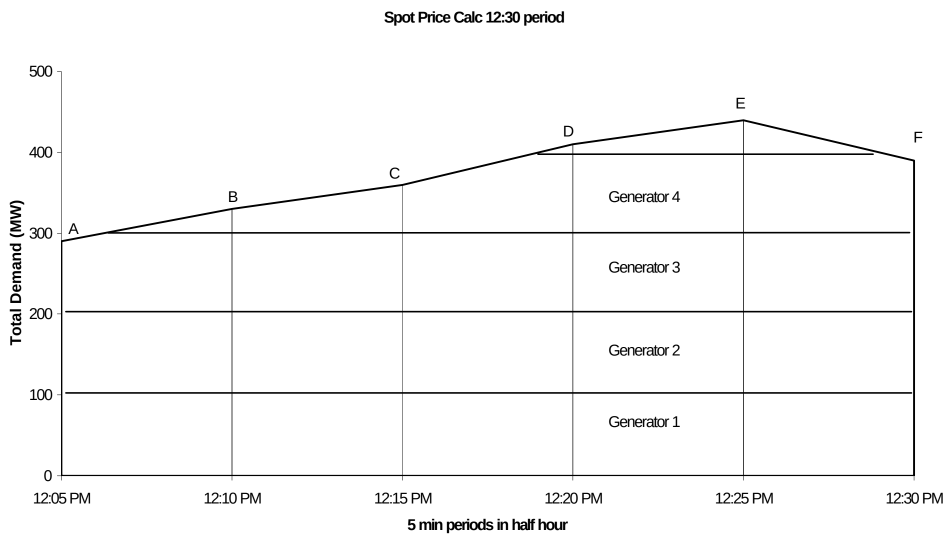


TABLE 2. *Dispatch of generation and spot price calculation*

Graph point price	Dispatch $/MWh	Time demand	Total (MW)	Scenario
Point A	35	12:05pm	290	Generators 1 & 2 are fully utilised. Generator 3 is partially utilised.
Point B	37	12:10pm	330	Generators 1,2 & 3 are fully utilised. Generator 4 is partially utilised.
Point C	37	12:15pm	360	Generators 1,2 & 3 are fully utilised. Generator 4 is partially utilised.
Point D	38	12:20pm	410	Generators 1,2, 3 & 4 are fully utilised. Generator 5 is partially utilised.
Point E	38	12:25pm	440	Generators 1,2, 3 & 4 are fully utilised. Generator 5 is partially utilised.
Point F	37	12:30pm	390	Generators 1,2 & 3 are fully utilised. Generator 4 is partially utilised.

The spot price is calculated as: ($35/MWh + $37/MWh + $37/MWh + $38/MWh + $38/MWh + $37/MWh) / 6 = $37/MWh

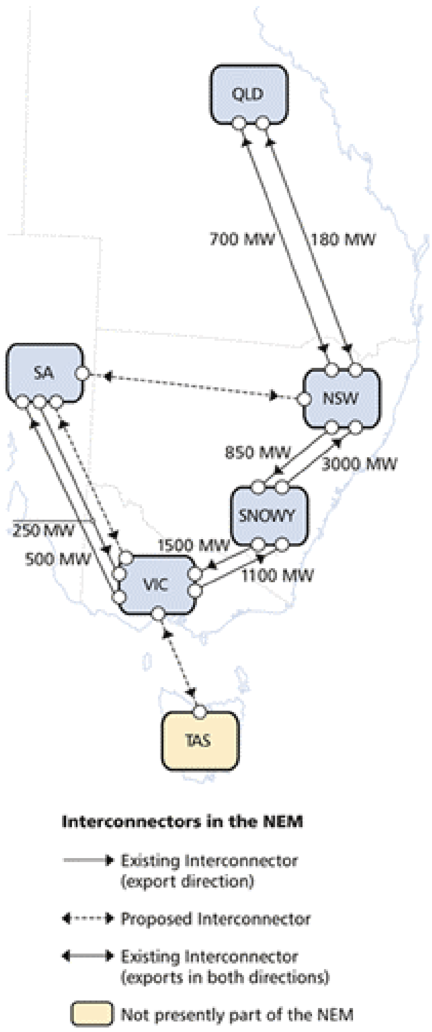
The spot pricing procedure, while bringing balance between supply and demand, can also expose participants to significant variation. This is owing to the dependence of the pool process on generator bidding strategies [for instance, Brennan et al. (1998) highlight the potential for holders of large generating portfolios to bid non-competitively in order to exercise market power] and the impact of the complex interaction of supply and demand factors on pricing. As such the spot price can be volatile, leading to large financial exposure. The occurrence of various phenomenon in the NEM have seen instances of high spot prices, and in some cases the maximum price cap for the NEM (Value of Lost Load) has been triggered.

Events in the past, which have had a tendency to drive NEM prices toward the upper end of the price spectrum, are of three types. First, prices can increase dramatically when a generation plant ‘trips’ or ‘falls over’, rendering it inoperable and forcing the plant’s contributed capacity to be removed from the bid stack. This is particularly the case if the plant provides base load output. Secondly, abnormal environmental temperatures drive demand up as customers increase their need for cooling or heating. Higher demand requires more generation to balance the system, which means plant bidding in at a higher price level on the least-cost merit order are sequentially dispatched to meet the additional demand. Third, technical constraints or faults with the systems design can also lead to higher prices. These three instances combined to cause an electricity supply crisis for Victoria in February 2000, as profiled by the IEA (2001: 123):

The Victorian outages reflected a combination of unusual circumstances, including an industrial dispute, which had taken around 20 per cent of generating capacity off line, two unplanned generator outages, and an extremely high peak demand caused by a heat wave across southeastern Australia. The situation was exacerbated by Victorian government intervention to introduce a price cap and establish consumption restrictions, which prolonged the shortages and distorted market responses…The mandatory consumption restrictions introduced by the Victorian government over six days lowered demand in Victoria and had the perverse effect of electricity flowing from Victoria into New South Wales and South Australia while the restrictions were in place.

Historically, each State in the NEM developed its own transmission network and linked it to another State's system via interconnector transmission lines. Power is transmitted between regions to meet energy demands that are higher than local generators can provide, or when the price of electricity in an adjoining region is low enough to displace the local supply. The scheduling of generators to meet demand across the interconnected power system is constrained by the physical transfer capacity of the interconnectors between the regions. When the limit of an interconnector is reached, NEMMCO schedules the most cost-efficient sources of supply from within the region to meet the remaining demand. For example, if prices are very low in Victoria and high in South Australia, up to 500 megawatts of electricity can be exported to South Australia across the interconnector. Once this limit is reached, the system will then use the lowest priced generators in South Australia to meet the outstanding consumer demand.

The limitations of transfer capability within the centrally coordinated and regulated NEM are one of its defining features. Queensland has two interconnectors that together can import and export 880 MW to and from NSW, NSW can export 850 MW to the Snowy and 3000 MW from the Snowy and Victoria can import 1500 MW from the Snowy and 250 MW from South Australia and export 1100 MW to the Snowy and 500 MW to South Australia. There is currently no direct connector between NSW and South Australia and Queensland is only connected directly to NSW.



The illustration of NEMMCO's dispatch and spot pricing methodology highlights the inherent volatility of the spot price, which can lead to large variations in financial exposure. This is owing to the dependence of the pool process on generator bidding strategies and the impact of the complex interaction of supply and demand factors on pricing. Further, while the appropriate regulatory and commercial mechanisms do exist for the creation of an efficient national market, and these are expected to have an impact on the price of electricity in each member jurisdiction, the complete integration of the five separate spot electricity markets has not yet been realised. In particular, the limitation of the interconnectors between the member jurisdictions suggests that for the most part the regional spot markets are relatively isolated, particularly in Queensland and South Australia. Nevertheless, the Victorian electricity crisis is just one of several shocks that suggests that spot electricity pricing and volatility in each Australian electricity spot market is potentially dependent on pricing conditions in the several other markets.

2. Data and summary statistics

The data employed in the study are daily spot prices for electricity encompassing the period from the date of commencement of the National Electricity Market (NEM) on 13 December 1998 to 30 June 2001. All price data is obtained from the National Electricity Market Company (NEMMCO) originally on a half-hourly basis representing 48 trading intervals in each 24-hour period. Following Lucia and Schwartz (2001) a series of daily arithmetic means is drawn from the trading interval data. Although such treatment entails the loss of at least some 'news' impounded in the more frequent trading interval data, daily averages play an important role in electricity markets, particularly in the case of financial contracts. For example, the electricity futures contract currently traded on the Sydney Futures Exchange (SFE) is settled against the arithmetic mean of half hourly spot prices in a given month. Moreover, De Vany and Walls (1999a; 1999b) and Robinson (2000) both employ daily spot prices in their respective analyses of the western United States and United Kingdom spot electricity markets.

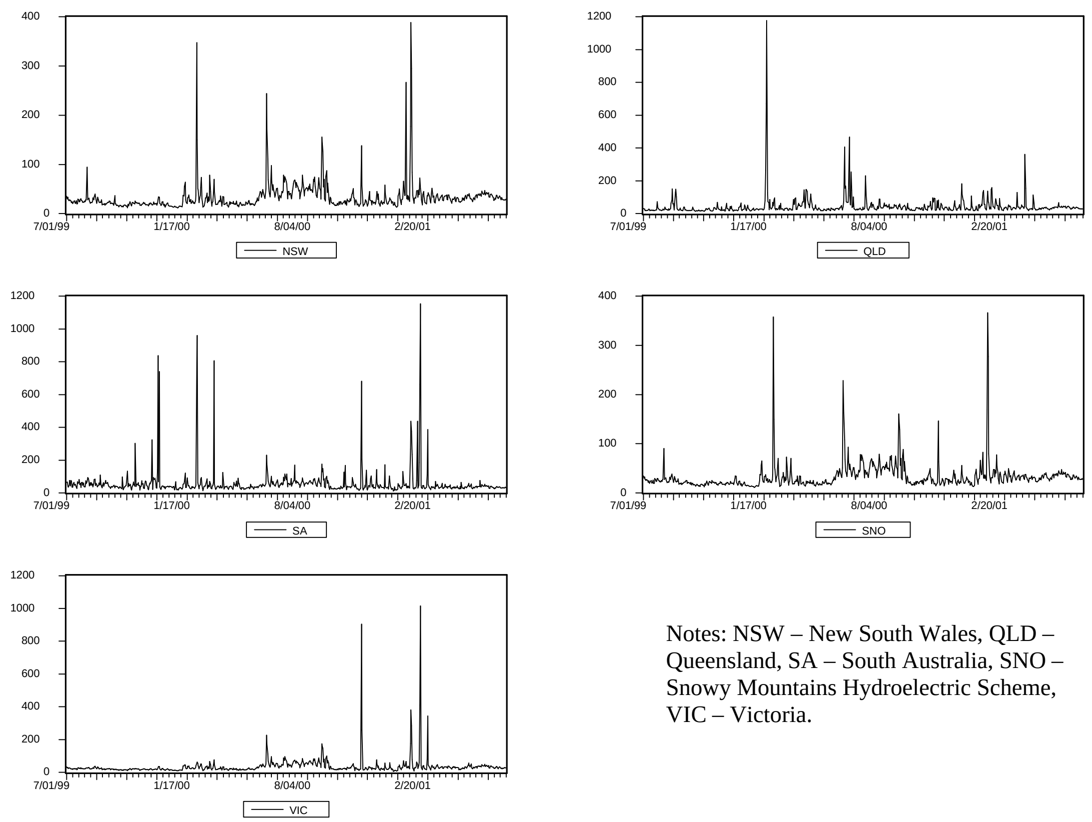
TABLE 3. *Summary statistics of spot prices in five Australian electricity markets*

	NSW	QLD	SA	SNO	VIC
Mean	33.0244	42.7055	57.9171	32.5624	35.5077
Median	26.4246	30.4117	38.9352	26.5121	25.3052
Maximum	388.2060	1175.5260	1152.5750	366.1698	1014.6010
Minimum	11.6533	13.2871	11.5225	11.0992	4.9785
Std. Dev.	29.6043	60.8140	92.1549	27.8366	58.5227
CV	0.8964	1.4240	1.5912	0.8549	1.6482
Skewness	6.8871	11.6290	7.6208	6.8653	12.0381
Kurtosis	66.2028	187.4572	69.3994	69.0835	179.8255
Jarque-Bera	127447	1052805	141362	138754	970003
JB probability	0.0000	0.0000	0.0000	0.0000	0.0000
ADF test	-5.5564	-7.6672	-8.8834	-6.1225	-8.2235

Notes: NSW – New South Wales, QLD – Queensland, SA – South Australia, SNO – Snowy Mountains Hydroelectric Scheme, VIC – Victoria. ADF – Augmented Dickey-Fuller test statistics; CV – coefficient of variation; JP – Jarque-Bera. Hypothesis for ADF test: H_0: unit root (non-stationary), H_1: no unit root (stationary). The lag orders in the ADF equations are determined by the significance of the coefficient for the lagged terms. Only intercepts are included. Critical values are -3.4420 at.01, -2.8659 at .05 and -2.5691 at the .10 levels.

Table 3 presents the summary of descriptive statistics of the daily spot prices for the five electricity markets. Samples means, medians, maximums, minimums, standard deviations, skewness, kurtosis and the Jacque-Bera statistic and *p*-value are reported. Between 13 December 1998 and 30 June 2001, the highest spot prices are in Queensland (QLD) and South Australia (SA) averaging $42.71 and $57.92 per megawatt-hour, respectively. The lowest spot prices are in New South Wales (NSW) and the Snowy Mountains Hydroelectric Scheme (SNO) with $33.02 and $32.56, respectively. The standard deviations for the spot electricity range from $27.84 (Snowy Mountains Hydroelectric Scheme) to $92.15 (South Australia). Of the five markets, New South Wales (NSW) and the Snowy Mountains Hydroelectric Scheme (SNO) are the least volatile, while Queensland (QLD) and South Australia (SA) are the most volatile. The value of the coefficient of variation (standard deviation divided by the mean price) measures the degree of variation in spot price relative to the mean spot price. Relative to the average spot price, New South Wales (NSW) and the Snowy Mountains Hydroelectric Scheme (SNO) are less variable than South Australia (SA) and Victoria (VIC). A visual perspective on the volatility of spot prices can be gained from the plots of daily spot prices for each series in Figure 2.

FIGURE 2. *Daily spot electricity prices for five Australian markets, 13/12/1998 – 30/6/2001*



Notes: NSW – New South Wales, QLD – Queensland, SA – South Australia, SNO – Snowy Mountains Hydroelectric Scheme, VIC – Victoria.

The distributional properties of the spot price series generally appear non-normal. All of the spot electricity markets are positively skewed and since the kurtosis, or degree of excess, in all of these electricity markets exceeds three, a leptokurtic distribution is also indicated. The calculated Jarque-Bera statistic and corresponding *p*-value in Table 3 is used to test the null hypotheses that the daily distribution of spot prices is normally distributed. All *p*-values are smaller than the .01 level of significance suggesting the null hypothesis cannot be rejected. These daily spot prices are then well approximated by the normal distribution. Lastly, each price series is tested for the presence of a unit root using the Augmented Dickey-Fuller (ADF) test. Contrary to previous empirical work De Vany and Walls (1999a; 1999b) which found that spot electricity prices contain a unit root, this study concurs with Lucia and Schwartz (2001) that electricity prices are stationary.

3. Multivariate GARCH model

Autoregressive conditional heteroscedasticity (ARCH) and generalised ARCH (GARCH) models that take into account the time-varying variances of univariate economic time series data have been widely employed. Suitable surveys of ARCH modeling in general and its widespread use in finance applications may be found in Bera and Higgins (1993) and Bollerslev et al. (1992) respectively. Pagan (1996) also contains discussion of recent developments in this expanding literature.

More recently, the univariate GARCH model has been extended to the multivariate GARCH (MGARCH) case, with the recognition that MGARCH models are potentially useful developments regarding the parameterization of conditional cross-moments. For example, Bollerslev (1990) used a MGARCH approach to examine the coherence in short-run nominal exchange rates, while Karolyi (1995) employed a similar model to examine the international transmission of stock returns between the United States and Canada. Dunne (1999) also employed a MGARCH model, though in the context of accommodating time variation in the systematic market-risk of the traditional capital asset pricing model (CAPM). And Kearney and Patton (2000) used a series of 3-, 4- and 5- variable MGARCH models to study the transmission of exchange rate volatility across European Monetary System (EMS) currencies prior to the introduction of the single currency. However, while the popularity of models such as these has increased in recent years, "…the number of reported studies of multivariate GARCH models remains small relative to the number of univariate studies" (Kearney and Patton 2000: 34).

The following MGARCH model is developed to examine the joint processes relating the daily spot prices for five electricity markets from 13 December 1998 to 30 June 2001. The sample period is chosen on the basis that it represents a continuous series of data since the establishment of the Australian National Electricity Market (NEM). The following conditional expected price equation accommodates each market's own prices and the prices of other markets lagged one period.

$$P_t = a + AP_{t-1} + e_t \tag{1}$$

where P_t is an $n \times 1$ vector of daily prices at time t for each market and $e_t | I_{t-1} \sim N(0, H_t)$. The $n \times 1$ vector of random errors, e_t is the innovation for each market at time t with its corresponding $n \times n$ conditional variance-covariance matrix, H_t. The market information available at time t - 1 is represented by the information set I_{t-1}. The $n \times 1$ vector, α, represent long-term drift coefficients. The elements a_{ij} of the matrix A are the degree of mean spillover effect across markets, or put differently, the current prices in market i that can be used to predict future prices (one day in advance) in market j. The estimates of the elements of the matrix, A, can provide measures of the significance of the own and cross-mean spillovers. This multivariate structure then enables the measurement of the effects of the innovations in the mean spot prices of one series on its own lagged prices and those of the lagged prices of other markets.

Engle and Kroner (1995) present various MGARCH models with variations to the conditional variance-covariance matrix of equations. For the purposes of the following analysis, the BEKK (Baba, Engle, Kraft and Kroner) model is employed, whereby the variance-covariance matrix of equations depends on the squares and cross products of innovation e_t and volatility H_t for each market lagged one period. One important feature of this specification is that it builds in sufficient generality, allowing the conditional variances and covariances of the electricity markets to influence each other, and, at the same time, does not require the estimation of a large number of parameters (Karolyi 1995). The model also ensures the condition of a positive semi-definite conditional variance-covariance matrix in the optimisation process, and is a necessary condition for the estimated variances to be zero or positive. The BEKK parameterisation for the MGARCH model is written as:

$$H_t = B'B + C'e_t e_{t-1} C + G'H_{t-1}G \tag{2}$$

where b_{ij} are elements of an $n \times n$ symmetric matrix of constants B, the elements c_{ij} of the symmetric $n \times n$ matrix C measure the degree of innovation from market i to market j, and the elements g_{ij} of the symmetric $n \times n$ matrix G indicate the persistence in conditional volatility between market i and market j. This can be expressed for the bivariate case of the BEKK as:

$$\begin{bmatrix} H_{11t} H_{12t} \\ H_{21t} H_{22t} \end{bmatrix} = B'B + \begin{bmatrix} c_{11} c_{12} \\ c_{21} c_{22} \end{bmatrix}' \begin{bmatrix} e_{1t-1}^2 e_{1t-1} e_{2t-1} \\ e_{2t-1} e_{1t-1} e_{2t-1}^2 \end{bmatrix} \begin{bmatrix} c_{11} c_{12} \\ c_{21} c_{22} \end{bmatrix} + \begin{bmatrix} g_{11} g_{12} \\ g_{21} g_{22} \end{bmatrix}' \begin{bmatrix} H_{11t-1} H_{12t-1} \\ H_{121t-1} H_{22t-1} \end{bmatrix} \begin{bmatrix} g_{11} g_{12} \\ g_{21} g_{22} \end{bmatrix} \tag{3}$$

In this parameterization, the parameters b_{ij}, c_{ij} and g_{ij} cannot be interpreted on an individual basis: "instead, the functions of the parameters which form the intercept terms and the coefficients of the lagged variance, covariance, and error terms that appear in [(3)] are of interest" (Kearney and Patton 2000: 36). With the assumption that the random errors are normally distributed, the log-likelihood function for the MGARCH model is:

$$L(?) = -\frac{Tn}{2} + \ln(2p) - \frac{1}{2}\sum_{t=1}^{T}\left(\ln|H_t| + e_t'|H_t^{-1}|e_t\right) \tag{4}$$

where T is the number of observations, n is the number of markets, q is the vector of parameters to be estimated, and all other variables are as previously defined. The BHHH (Berndt, Hall, Hall and Hausman) algorithm is used to produce the maximum likelihood parameter estimates and their corresponding asymptotic standard errors. Overall, the proposed model has twenty-five parameters in the mean equations, excluding the five constant (intercept) parameters, and twenty-five intercept, twenty-five white noise and twenty-five volatility parameters in the estimation of the covariance process, giving one hundred and five parameters in total.

Lastly, the Ljung-Box Q statistic is used to test for independence of higher relationships as manifested in volatility clustering by the MGARCH model [Huang and Yang 2000:329]. This statistic is given by:

$$Q = T(T+2)\sum_{j=1}^{p}(T-j)^{-1} r^2(j) \tag{5}$$

where $r(j)$ is the sample autocorrelation at lag j calculated from the noise terms and T is the number of observations. Q is asymptotically distributed as χ^2 with (p - k) degrees of freedom and k is the number of explanatory variables. The test statistic in (5) is used to test the null hypothesis that the model is independent of the higher order volatility relationships.

4. Empirical results

The estimated coefficients and standard errors for the conditional mean price equations are presented in Table 4. For the five electricity spot markets only QLD and SNO exhibit a significant own mean spillover from their own lagged electricity price. In both cases, the mean spillovers are positive. For example, in QLD a $1.00 per megawatt-hour increase in its own spot price will Granger cause an increase of $0.51 per megawatt-hour in its price over the next day. Likewise, a $1.00 per megawatt-hour increase in the SNO lagged spot price will Granger cause a $0.70 increase the next day. Importantly, there are no significant lagged mean spillovers from any of the spot markets to any of the other markets. This indicates that on average short-run price changes in any of the five Australian spot markets are not associated with price changes in any of the other spot electricity markets, despite the connectivity offered by the NEM.

Table 4. *Estimated coefficients for conditional mean price equations*

	NSW (i = 1)		QLD (i = 2)		SA (i = 3)		SNO (i = 4)		VIC (i = 5)	
	Estimated coefficient	Standard error	Estimated coefficient	Standard error	Estimated coefficient	Standard error	Estimated coefficient	Standard error	Estimated coefficient	Standard error
CONS.	**12.8966	6.8610	*16.0313	11.3500	16.18667	18.8600	**12.2740	5.5630	11.2951	20.7400
a_{i1}	0.0497	0.7556	-0.0135	0.0951	-0.0237	0.0844	0.5977	0.8215	0.0248	0.1749
a_{i2}	0.0410	2.0470	***0.5118	0.1291	-0.0658	0.2296	0.2046	2.2010	0.0321	0.4654
a_{i3}	-0.1159	5.5800	-0.0529	0.3520	0.2493	0.1946	1.0097	5.6880	-0.0344	0.6905
a_{i4}	-0.0548	0.2984	-0.0131	0.0778	-0.0265	0.0557	**0.7001	0.3884	0.0318	0.1425
a_{i5}	-0.1641	4.0450	-0.0049	0.3352	0.0310	0.1113	0.4664	4.0390	0.3102	0.5095

Notes: NSW – New South Wales, QLD – Queensland, SA – South Australia, SNO – Snowy Mountains Hydroelectric Scheme, VIC – Victoria. Asterisks indicate significance at * - 0.10, ** - 0.05, *** - 0.01 level

The conditional variance covariance equations incorporated in the paper's multivariate GARCH methodology effectively capture the volatility and cross volatility spillovers among the five spot electricity markets. These have not been considered by previous studies. Table 5 presents the estimated coefficients for the variance covariance matrix of equations. These quantify the effects of the lagged own and cross innovations and lagged own and cross volatility persistence on the own and cross volatility of the electricity markets. The coefficients of the variance covariance equations are generally significant for own and cross innovations and significant for own and cross volatility spillovers to the individual prices for all electricity markets, indicating the presence of strong ARCH and GARCH effects. In evidence, 68 percent (seventeen out of twenty-five) of the estimated ARCH coefficients and 84 percent (twenty-one out of twenty-five) of the estimated GARCH coefficients are significant at the .10 level or lower.

Own-innovation spillovers in all the electricity markets are large and significant indicating the presence of strong ARCH effects. The own-innovation spillover effects range from 0.0915 in VIC to 0.1046 in SNO. In terms of cross-innovation effects in the electricity markets, past innovations in most markets exert an influence on the remaining electricity markets. For example, in the case of VIC cross innovation in the NSW, SA and SNO markets are significant, of which NSW has the largest effect. The exception to the presence of strong cross innovation effects is QLD. No cross innovations outside of QLD influence that market, and the QLD market does influence any of the other electricity markets, at least over the period in question. This is consistent with the role of QLD in the NEM in that it has only limited direct connectivity with just one other regional spot market (NSW).

In the GARCH set of parameters, eighty-four percent of the estimated coefficients are significant. For NSW the lagged volatility spillover effects range from 0.7839 for SA to 0.8412 for QLD. This means that the past volatility shocks in QLD have a greater effect on the future NSW volatility over time than the past volatility shocks in other spot markets. Conversely, in QLD the post volatility shocks range from 0.65212 for SA to 0.8413 for SNO. In terms of cross-volatility for the GARCH parameters, the most influential markets would appear to be NSW and SNO. That is, past volatility shocks in the NSW and SNO electricity spot markets have the greatest effect on the future volatility in the three remaining electricity markets.

TABLE 5. *Estimated coefficients for variance covariance equations*

	NSW (j = 1)		QLD (j = 2)		SA (j = 3)		SNO (j = 4)		VIC (j = 5)	
	Estimated coefficient	Standard error	Estimated coefficient	Standard error	Estimated coefficient	Standard error	Estimated coefficient	Standard error	Estimated coefficient	Standard error
b_{1j}	***80.2657	16.6300	18.7260	59.5500	120.9672	124.3000	***71.3986	12.8500	75.8586	78.8900
b_{2j}	18.7260	59.5500	***336.6956	99.0900	41.1680	332.7000	17.1266	66.2000	31.8362	285.4000
b_{3j}	120.9672	124.3000	41.1680	332.7000	**635.0478	353.4000	*120.0339	88.1800	229.8638	219.7000
b_{4j}	***71.3986	12.8500	17.1266	66.2000	*120.0339	88.1800	***67.6679	11.7500	**75.3265	41.9500
b_{5j}	75.8586	78.8900	31.8362	285.4000	229.8638	219.7000	**75.3265	41.9500	***295.1421	62.2100
c_{1j}	***0.0985	0.0140	0.0997	0.1735	***0.0989	0.0278	***0.1013	0.0043	***0.0992	0.0221
c_{2j}	0.0997	0.1735	***0.1008	0.0198	0.1232	0.2944	0.0993	0.2777	0.0834	0.3979
c_{3j}	***0.0989	0.0278	0.1232	0.2944	***0.0991	0.0216	***0.1021	0.0126	***0.0937	0.0211
c_{4j}	***0.1013	0.0043	0.0993	0.2777	***0.1021	0.0126	***0.1046	0.0105	***0.0978	0.0175
c_{5j}	***0.0992	0.0221	0.0834	0.3979	***0.0937	0.0211	***0.0978	0.0175	***0.0915	0.0249
g_{1j}	***0.8047	0.0133	***0.8412	0.3192	***0.7839	0.0959	***0.8080	0.0001	***0.8034	0.0447
g_{2j}	***0.8412	0.3192	***0.8051	0.0416	0.6520	1.3560	**0.8413	0.4615	0.8234	1.0580
g_{3j}	***0.7839	0.0959	0.6520	1.3560	***0.8107	0.0309	***0.7868	0.0961	***0.8148	0.0263
g_{4j}	***0.8080	0.0001	**0.8413	0.4615	***0.7868	0.0961	***0.8098	0.0128	***0.8056	0.0316
g_{5j}	***0.8034	0.0447	0.8234	1.0580	***0.8148	0.0263	***0.8056	0.0316	***0.8119	0.0233

Notes: NSW – New South Wales, QLD – Queensland, SA – South Australia, SNO – Snowy Mountains Hydroelectric Scheme, VIC – Victoria. Asterisks indicate significance at * - 0.10, ** - 0.05, *** - 0.01 level

The sum of the ARCH and GARCH coefficients measures the overall persistence in each market's own and cross conditional volatility. All five electricity markets exhibit strong own persistence volatility ranging from 0.9032 for NSW to 0.9143 for SNO. Thus, SNO has a lead-persistence volatility spillover effect on the remaining electricity markets. The cross-volatility persistence spillover effects range from 0.7751 for SA 0.9409 for QLD.

TABLE 6. *Ljung-Box tests for standardized residuals*

	NSW	QLD	SA	SNO	VIC
Statistic	27.0100	32.4600	44.7000	17.9700	50.8700
p-value	0.0077	0.0012	0.0000	0.1166	0.0000

Finally, the Ljung-Box (LB) Q statistics for the standardised residuals in Table 6 reveal that all electricity spot markets are highly significant (all have p-values of less than .01) with the exception of SNO (a p-value of 0.1166). Significance of the Ljung-Box (LB) Q statistics for the electricity spot price series indicates linear dependences due to the strong conditional heteroskedasticity. These Ljung-Box statistics then suggest a strong linear dependence in four out of the five electricity spot markets estimated by the MGARCH model.

5. Concluding remarks

This paper highlights the transmission of prices and price volatility among five Australian electricity spot markets during the period 1998 to 2001. All of these spot markets are member jurisdictions of the recently established National Electricity Market (NEM). At the outset, unit root tests confirm that Australian electricity spot prices are stationary. A multivariate generalised autoregressive conditional heteroskedasticity (MGARCH) model is used to identify the source and magnitude of spillovers. The estimated coefficients from the conditional mean price equations indicate that despite the presence of a national market for electricity, the state-based electricity spot markets are not integrated. In fact, only two of the five markets exhibit a significant own mean spillover. This would suggest, for the most part, that Australian spot electricity prices could not be usefully forecasted using lagged price information from either each market itself or from other markets in the national market. However, own-volatility and cross-volatility spillovers are significant for nearly all markets, indicating the presence of strong ARCH and GARCH effects. Strong own and cross-persistent volatility are also evident in all Australian electricity markets. This indicates that while the limited nature of the interconnectors between the separate regional spot markets prevents full integration of these markets, shocks or innovations in particular markets still exert an influence on price volatility.

Of course, the full nature of the price and volatility interrelationships between these separate markets could be either under or overstated by misspecification in the data. One possibility is that by averaging the half-hourly prices throughout the day, the speed at which innovations in one market influence another could be understated. For instance, with the data as specified the most rapid innovation allowed in this study is a day, whereas in reality innovations in some markets may affect others within just a few hours. Similarly, there has been no attempt to separate the differing conditions expected between peak and off-peak prices. For example, De Vany and Walls (1999) found that there were essentially no price differentials between trading points in off-peak periods because they were less constrained by limitations in the transmission system. These limitations, of course, suggest future avenues of research.

The analysis could also be extended in a number of other ways. One approach would be to estimate a system of non-symmetrical conditional variance equations for an identical set of data. This would allow the analysis of cross volatility innovations and persistence to vary according to the direction of the information flow. Unfortunately, strict computing requirements did not permit the application of this model with the five electricity markets specified in the analysis. Another useful extension would be to examine each of the five electricity markets individually and in more detail. For example, while the sample for this study is determined by the period of tenure of the National Electricity Market (NEM) wholesale electricity spot markets in the separate states pre-date this by several years. An examination of the connection between the long-standing electricity spot markets in NSW and VIC would be particularly useful. Finally, the Sydney Futures Exchange (2000) has offered electricity futures contracts for two of Australia's NEM jurisdictions, NSW and Victoria, since September 1997. An examination of the relationship between Australian spot and derivative electricity prices using, say, cointegration techniques would then be interesting.

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